Modeling Solvent Enhanced Gravity Drainage from a Single Matrix Block in Fractured Oil Reservoirs

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Abstract

Solvent based oil recovery is one of the fast growing methods for low emissions-intensity oil recovery from underground resources. In particular, in fractured reservoirs, miscible solvents are injected, and through diffusion and dispersion processes they mix with oil inside the matrix blocks where the oil phase viscosity can be reduced. Consequently, gravity drives the solvent-oil mixture from matrix into fractures, and drained oil is then produced from fracture network. In low permeability matrix blocks or reservoirs with viscous oil, diffusion and convection controls the rate of mass transfer between oil in matrix blocks and solvent in fractures. This study provides a novel semi-analytical solutions that can accurately estimate the mass transfer rates and oil recovery from matrix blocks under gravity drainage. The theoretical results using realistic diffusivity coefficients can accurately match the experimentally measured solvent concentration profiles inside the matrix block. Furthermore, an optimization strategy based on the new model is developed that can be used for a quick evaluation of solvent choice for different oil types and reservoir properties.

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Keywords: solvent-based recovery; fractured reservoirs; solvent diffusion; concentration-dependent diffusivity; gravity drainage

Nomenclature

c	:	volumetric solvent concentration [ML^{-3}]
D	:	diffusion coefficient [L^2T^{-1}]
D_0	:	constant of concentration dependent diffusion coefficient [L^2T^{-1}]
g	:	gravity constant [L^2T^{-1}]
k	:	permeability [L^2]
l	:	characteristic length [L]
n	:	exponent to concentration [-]
Pe	:	Peclet number [-]
q	:	sink term [$ML^{-3}T^{-1}$]
t	:	time [T]
u	:	Darcy velocity [LT^{-1}]
V	:	volume fraction [-]
x	:	length coordinate inside matrix [L]
x_s	:	Shu's compositional parameter [-]

Greek

α	:	empirical constant in viscosity correlation [-]
ϕ		porosity of the matrix [-]
ρ	:	density [ML^{-3}]
μ	:	dynamic viscosity [MLT^{-1}]
ν	:	Kinematic viscosity [L^2T^{-1}]

Subscript

D	:	dimensionless
mix	:	mixture
o	:	oil
s	:	solvent

1. Introduction

High fracture-to-matrix permeability ratio is the main feature of fractured reservoirs that makes oil recovery from these reservoirs difficult in most cases (Saidi 1987). Gravity drainage,

capillary and viscous forces are important drive mechanisms for oil production from matrix blocks (Karimaie and Torsaeter 2008; Pooladi-Darvish and Firoozabadi 2000). In fractured reservoirs, conventional methods such as water flooding and gas injection have shown good recovery performances (Mattax and Kyte 1962; de Swaan 1978; Karimaie et al. 2007). Also, miscible displacement improves oil recovery from fractured reservoirs (Firoozabadi et al. 1997; Torabi et al. 2012). There are huge reserves of heavy oil locked in fractured carbonate reservoirs around the world, for instance in the Middle East, Canada, and Russia (Antoniadi et al. 1988; Briggs et al. 1988; Baibakov and Garushev 1989; Ezeuko et al. 2015). In some cases, the oil is not mobile at reservoir conditions. Oil recovery from oil sands and heavy oil reservoirs requires first that the oil viscosity is lowered. This is often accomplished by either thermal processes, i.e. introducing heat to raise the temperature of oil or by solvent dilution, i.e. mixing oil with solvents. Examples are SAGD; steam-assisted gravity-drainage, VAPEX; vapour extraction, ES-SAGD; expanding solvent SAGD, to name a few (Butler and Stevens 1981; Butler and Mokrys 1989, 1991; Dunn et al. 1981; Jiang et al. 2014).

Thermal processes that have demonstrated successful commercial performance in oil sands reservoirs have also been proposed to recover heavy oil from fractured rocks (Butler and Mokrys 1989, 1989; Pooladi-Darvish and Farouq Ali 1994; Rahnema et al. 2008; Ezeko et al. 2015). However, challenges related to the steam channelling through fractures and vuggy intervals remains unresolved. In these reservoirs, condensate bypasses matrix blocks with matrix heating dominated by conduction; thus it may not yield high recovery factor as encountered in oil sands operations (Penny et al. 2005).

Therefore, using solvents might be a good solution for oil recovery from these reservoirs. The key advantage of miscible hydrocarbon solvents compared to immiscible gas injection is the ability of the solvent to mix completely with the oil (in all proportions). Hence, capillary effects vanish which consequently leads to lower residual oil saturation and higher recovery factor than would be the case with immiscible mixing. In deep reservoirs that are composed of mainly heavy components, use of hydrocarbon gas requires high compression costs to reach miscible conditions. Also in shallow heavy oil reservoirs, use of heavier hydrocarbon solvents are suitable compared to gas injection (Gates 2007; Chahardowli et al. 2013; Pathak et al. 2013; Mayorquin-Ruiz and Babadagli 2016). Oliveira et al. (2009) discussed that oil viscosity and type of the solvent are very important parameters to improve the oil recovery in heavy oil reservoirs. They found that the heavier solvents achieve higher recovery factors which is related to the oil-solvent miscibility development and oil mobilizing by reducing its viscosity.

Oil recovery with solvent injection mainly depends on the diffusion of solvent and its mixing due to natural convention in the matrix blocks (Kahrobaei et al. 2012). Diffusion of solvent is a very slow process and is not practical as an enhanced oil recovery method, however, gravity driven convection with counter-current flow is a promising solution for many fractured reservoirs from heavy to light oils (Darvish et al. 2006; Hatiboglu and Babadagli 2008; Rankin et al. 2014; Leyva-Gomez and Babadagli 2016).

The impact of diffusion has been studied by several investigators for enhanced oil recovery from fractured reservoirs (Jamshidnezhad et al. 2004; Darvish et al. 2006; Karimaei and Torsaeter, 2008). Rich solvents showed important recovery performance in laboratory analysis for fractured rocks (Chahardowli et al., 2013). Hatiboglu and Babadagli (2008) used pentane to understand

flow mechanisms in fractured rocks through micro model studies. They reported that diffusion reduces the viscosity of the oil and then natural density-driven convection triggered by the solvent fingering improves oil-solvent mixing. Trivedi and Babadagli (2008) experimentally analysed the role diffusion process in oil recovery from fractured rocks by using solvents. Their study showed that diffusion and injection rate affect final recovery. At an optimum injection rate where solvent can diffuse from fracture into the matrix block, viscosity reduction due to solvent mixing, increases the recovery factor. Kahrobaie et al. (2012) analysed X-ray tomography of solvent concentration and oil recovery from core samples. Their study suggested that diffusion of solvent into the rock matrix block and then subsequent mixing helped to mobilize oil from matrix blocks. They attempted to simulate their experiment with a reservoir simulator (Shell's MoReS simulator). However, in some cases, the software was not capable of reproducing the experimental data with reasonable values of the diffusion coefficient. To get a match between the simulation results and experimental data, they used diffusion coefficients with orders of magnitude smaller than those reported in the literature. Against these promising experimental results for solvent enhanced oil recovery, models and simulators are not able to fully incorporate full diffusion behaviour observed in experiments (Kahrobaie et al. 2012). This includes diffusion coefficient dependence on temperature and concentration. This dependence has been found necessary for other solvent-based processes (Trivedi and Babadagli 2008).

In this study a model is developed to describe mass transfer process in miscible enhanced oil recovery method from fractured reservoirs. A concentration dependent diffusion coefficient is used for the solvent-oil system. Simulation results are compared for different solvent and oil properties, and, optimization of solvent is discussed.

2. Conceptual Model

We define the fracture geometry as parallel planar gaps which separate slab-shaped matrix blocks. Figure 1 shows the schematic of fracture and matrix block. It is assumed that a repetitive element shown in this model represents a matrix block surrounded by fracture in the reservoir. In this model, one dimensional diffusion and flow inside the matrix block perpendicular to the fracture plane occur. We assume that the oil mobility is very low, initially, due to its very high viscosity. The main oil recovery mechanism from the matrix block is oil dilution through solvent-oil diffusion and consequently gravity drainage, i.e. denser diluted oil is replaced by lower density solvent. Thus a density contrast between oil and injected solvent is required to augment the gravity drainage process. Typically, solvents have lower density than oil. It is assumed that solvent fills the fractures where permeability is high, and its concentration inside the fractures is reasonably constant. Also oil expansion (swelling) is assumed to be negligible. The mass transfer process initially starts with solvent diffusion into the matrix block from the interface of matrix-fracture where solvent concentration is constant. As solvent diffuses into the matrix block, it mixes with oil and reduces oil viscosity. Thereafter, a counter-current flow is triggered due to the density contrast between the solvent and oil-solvent mixture. This counter-current flow develops dispersion in the matrix block (convective mixing). The process continues until solvent penetrates the entire matrix.

3. Mathematical Model

One dimensional flow of solvent and oil happens at the interface of matrix and fracture. The rate of solvent penetration into the matrix block and oil flow to the fracture are key. Thus, we

develop a model which describe the mass transfer process in a matrix block and gives the corresponding oil flow rate based on the fluids and rock properties of the system. Mass transfer process at the matrix block is controlled initially by Fick's second law at the interface of solvent and oil, and then Darcy's law controls the gravity drainage. Therefore, the counter-current flow of oil and solvent can be expressed by coupling of continuity equation and Darcy's law as a nonlinear diffusion equation which counts for convective and diffusive mass transfer (Marle, 1981):

$$\frac{\partial c}{\partial t} = \frac{\partial}{\partial x}\left(D\frac{\partial c}{\partial x}\right) - \frac{1}{2\phi}\frac{\partial}{\partial x}(uc) + \Delta q \qquad (1)$$

where c is the volumetric solvent concentration, t is time, D is effective solvent diffusion coefficient, and x is coordinate perpendicular to the interface plane of fracture and matrix and ϕ is the matrix porosity. Δq is the sink term which represents the counter-current flow of the mixture of solvent and oil toward the fracture plane (for solvents heavier than oil), or toward the middle of matrix block (for solvents lighter than oil), and has a unit of mass per volume per time. Theoretically it has the same magnitude as convective term but flow happens in opposite direction of convective term. It is assumed that produced mixture at the interface of matrix-fracture is recovered immediately, i.e., fracture is always saturated with solvent. Therefore, in Equation (1) convective and counter-current terms contribute to the solvent flow due to gravity force. Due to full miscibility condition, half of the cross sectional area is available to convective flow and the other half is available to counter-current flow, therefore, there is a coefficient of 0.5 in front of convective term. We further assume ideal mixing, i.e. volume remains perfectly additive upon mixing. In the above equation, the velocity is given by:

$$u = -\frac{kk_r g}{\mu}\Delta\rho \quad (2)$$

where k and k_r are matrix absolute and relative permeabilities (relative permeability is equal to unity for miscible conditions), g represents constant of gravity, $\Delta\rho$ is the difference between mixture density at any two points that causes a change in hydraulic head and therefore gravity drainage of oil. This density difference is a function of solvent concentration. And μ is viscosity of the mixture of oil and solvent.

Initial and boundary conditions for Equation (1) are:

$$c(x,t) = 0, \qquad t = 0, \ \ 0 \le x \le l \quad (3a)$$

$$c(x,t) = c_s, \qquad t > 0, \ \ x = 0 \quad (3b)$$

$$\frac{\partial c(x,t)}{\partial x} = 0, \qquad t > 0, \ \ x = l \quad (3c)$$

where l is the characteristic length of the rock matrix blocks; which is the half length of the matrix block if fracture planes are extending vertically (gravity assisted flow happens from both sides of fracture planes), or it is equal to the fracture spacing for horizontal fracture planes (gravity assisted flow happens from lower fracture plane) as shown in Figure 1.

There are different correlations in the literature for the concentration-dependent viscosity profiles such as log-linear and power-function mixing rules (Lederer 1933; Shu 1984). We use a power-function to define the oil-solvent mixture viscosity as:

$$\frac{1}{\mu_{\mathrm{mix}}} = \frac{1}{\mu_{\mathrm{o}}}\left(\frac{\mu_{\mathrm{o}}}{\mu_{\mathrm{s}}}\right)^{x_s} \quad (4)$$

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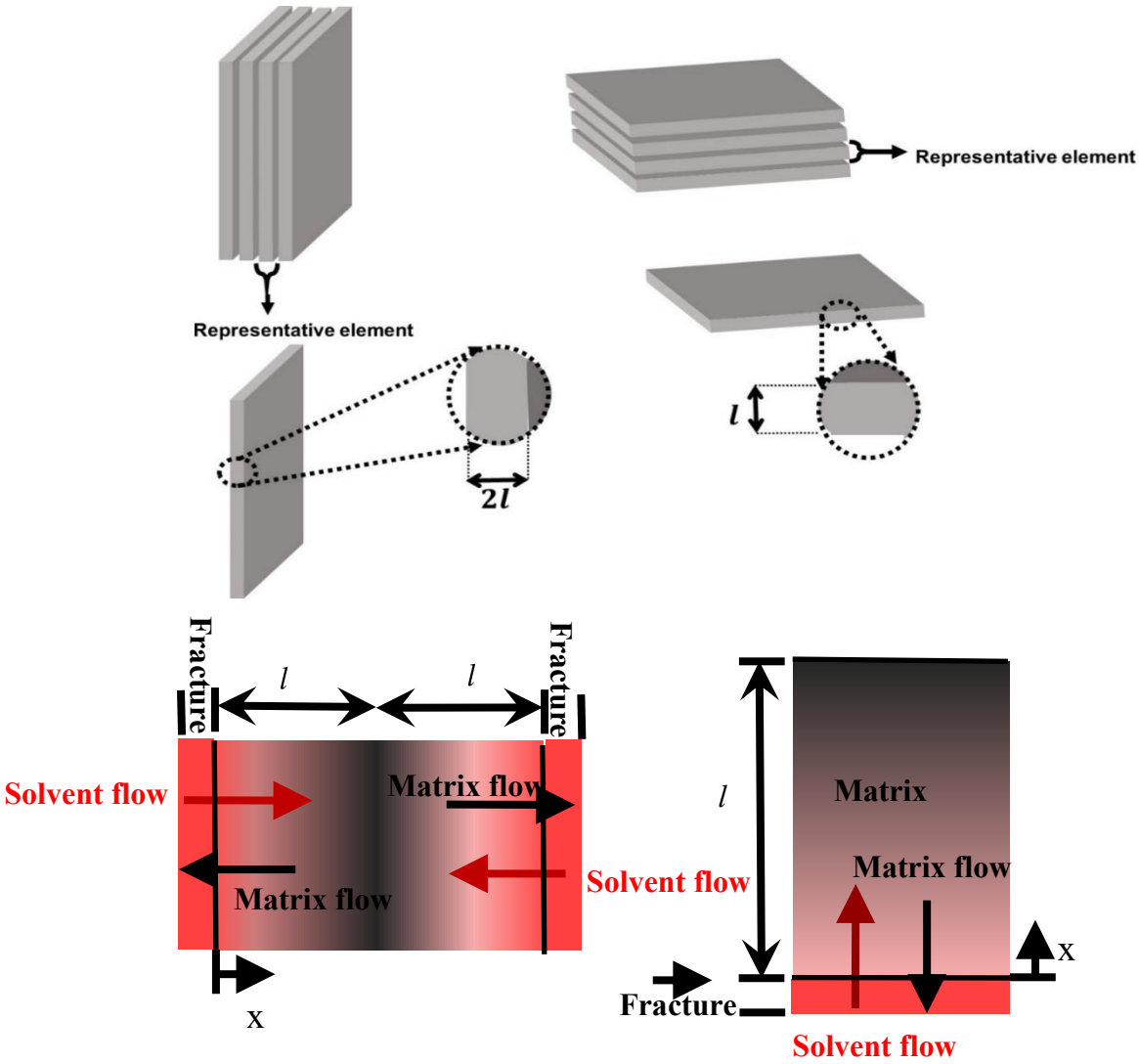

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160 **Figure 1:** Schematic of planar matrix blocks and characteristic length based on the fracture

161 orientation.

162

163 where μ is the viscosity of the mixture (subscribe 'mix') or oil and solvent phase (subscribe 'o'

164 or 's' respectively). x_s is a compositional parameter defined by Shu (1984):

$$x_s = \frac{V_s}{\alpha V_o + V_s} \quad (5)$$

where V_o and V_s are volume fractions of oil and solvent in the mixture, same as concentration, and α is an empirical constant have a value between zero and one. We used 0.6 in this study based on the typical values reported in Shu's work (1984). For the density of the mixture, a simple volumetric mixing rule is used as:

$$\rho = \rho_s V_s + \rho_o V_o \quad (6)$$

Based on the previous laboratory and modelling studies (Guerrero et al. 2008; Okazawa 2009; Diedro et al. 2015) it is reported that diffusion coefficient is not constant, rather it is a concentration dependent parameter. In this study we use the model suggested by Okazawa (2009) for concentration dependency of the diffusion coefficient:

$$D(c) = D_0 \left(\frac{c}{c_s}\right)^n \quad (7)$$

In Equation (7), D is concentration dependent diffusion coefficient, D_0 is constant of concentration dependent diffusion coefficient, and n is the exponent to concentration for diffusion coefficient; typically between 1-4 for oil and solvent system. This equation has been developed based on experimental tests with different heavy oils and solvents. Once these functions of diffusion coefficient, density and viscosity of mixture are applied to the formulation of mass transfer in matrix block, it gives a partial differential equations with two nonlinear terms.

$$\frac{\partial c}{\partial t} = \frac{\partial}{\partial x}\left(D_0 (\frac{c}{c_s})^n \frac{\partial c}{\partial x}\right) + \frac{1}{2\phi}\frac{\partial}{\partial x}\left(\left(\frac{\mu_o}{\mu_s}\right)^{x_s} \frac{kg}{\mu_o}\Delta\rho c\right) + \Delta q \quad (8)$$

Using dimensionless variables, Equation (8) can be written as:

$$\frac{\partial c_{\mathrm{D}}}{\partial t_{\mathrm{D}}} = \frac{\partial}{\partial x_{\mathrm{D}}}\left(c_{\mathrm{D}}^{\mathrm{n}} \frac{\partial c_{\mathrm{D}}}{\partial x_{\mathrm{D}}}\right) + \frac{Pe}{2}\frac{\partial}{\partial x_{\mathrm{D}}}\left(\mu_{\mathrm{D}}^{\mathrm{x_s}} \rho_{\mathrm{D}} c_{\mathrm{D}}\right) + q_{\mathrm{D}} \quad (9a)$$

where

$$\mu_{\mathrm{D}} = \frac{\mu_{\mathrm{o}}}{\mu_{\mathrm{s}}} \quad (9b)$$

$$c_{\mathrm{D}} = \frac{c}{c_{\mathrm{s}}} \quad (9c)$$

$$x_{\mathrm{D}} = \frac{x}{l} \quad (9d)$$

$$t_{\mathrm{D}} = \frac{tD_0}{l^2} \quad (9e)$$

$$\rho_{\mathrm{D}} = \frac{\Delta\rho}{\rho_{\mathrm{o}}} \quad (9f)$$

$$Pe = \frac{kgl}{D_0 \upsilon_{\mathrm{o}\phi}} \quad (9g)$$

$$q_{\mathrm{D}} = \frac{\Delta q l^2}{D_0 c_s} \quad (9h)$$

In the above equation, Pe is the Peclet number which is the ratio of the convective to diffusive terms. A Peclet number of zero corresponds to pure diffusion mass transfer process, and values greater than zero signify convective mixing and gravity drainage in the oil recovery process in addition to the diffusion process.

Due to the nonlinearity of Equation 8, we cannot provide a closed form analytical solution. Thus we solve Equation 8 numerically to find the evolution of solvent concentration distribution in the matrix block and consequently evaluate oil production. And oil recovery factor can be estimated through a numerical integration of the solvent concentration over the matrix block height at any time. We use central finite difference for mass diffusion and convection terms and forward

206 difference for marching in time. It should be noted that for the diffusion coefficient, downwind
207 formulation is used as similar to the direction of solvent penetration, however, for density and
208 viscosity of the mixture upwind formulation is considered as convective and counter-current
209 flow starts in the opposite direction of solvent penetration.

210 **4. Numerical solution and comparison with experimental data**

211 To validate our model, we compare the simulation results of our model with experimental data.
212 We simulate the solvent penetration depth and oil recovery for an experimental study reported as
213 a nearly one-dimensional (1D) flow for oil recovery from a matrix block (Kahrobaei et al.,
214 2012). They used hexadecane as oil and decalin as solvent in low permeability core sample.
215 Table 1 shows the details of the rock and fluid properties used in the experiment. They showed
216 that the solvent concentration increases inside the rock matrix with time as oil is produced due to
217 gravity drainage. They used CT-scan at various times and found the concentration profiles inside
218 the core sample by CT-scan image analysis. They reported up to 100% oil recovery which
219 indicates a miscible single phase process. In the same study, Kahrobaei et al. (2012) performed
220 numerical simulations of the process by using a multiphase reservoir simulator (Shell's MoReS).
221 Their simulations results demonstrate that reproducing solvent concentration profile inside the
222 rock matrix blocks may not be achievable. Moreover, the oil recovery profile was not matched
223 with a reasonable value of the diffusion coefficient values.
224
225 By using experimental values for oil, solvent and rock properties, we simulate the process with
226 Pe number and viscosity ratio of 0.25 and 1.05, respectively, extracted from reported
227 experimental data. Figure 2a-b depicts concentration and oil recovery profiles (solid lines) from

our numerical simulation, respectively. For comparison purposes, in Fig.2a-b, we also plot the reported experimental solvent concentration data and recovery (dotted lines) from Kahrobaei et al. (2012). Figure 2 demonstrates that the new model proposed here predicts the solvent concentration profile in the core and total recovery factor from the rock matrix block reasonably well. All parameters are from the experimental study. The matching parameters in our model are n and D_0 which are chosen to be 2 and 1.75×10^{-8} m^2/s respectively. The value of D_0 is in the range of reported values for solvent diffusion coefficient into oil (Guerrero et al., 2008; Okazawa, 2009; Diedro et al., 2015). Concentration dependent diffusion coefficient was developed based on the experimental data from heavy oil and solvent mixtures, and with the lack of enough experimental data for light oil-solvent mixtures, we assume this concentration dependent diffusion coefficient is applicable for other oil viscosities as well. Also the study of Kahrobaei et al. (2012) showed that diffusion coefficient in their numerical simulation should be very small to capture the behaviour of solvent diffusion, therefore, the concentration dependent diffusion coefficient might be the reason for such behaviour. Further studies are required to confirm this correlation of concentration dependent diffusion coefficient for light oil-solvent mixtures.

Table 1 Fluid and rock properties used in the experimental study (Kahrobaei et al. 2012)

Property	**Value**
Oil (hexadecane) viscosity	3.507 cP
Solvent (decalin) viscosity	3.355 cP
Core porosity	21%
Core permeability	20 mD

Temperature	20°C

It should be noted that the original experiment is performed in a cylindrical core samples when the whole sample is submerged into the solvent container. This allows for additional oil recovery resulting from the side of cylinder in addition to the bottom side. However, CT images of the experiment that we modelled in this study depict that the solvent penetration and oil production is very small which justifies the 1D assumption. On the other hand, this small additional oil production could be the source of discrepancy between the model and experimental data in Figure 2a. However, it is a small deviation as seen between the recovery factors calculated from the model and reported experimental values as shown in Figure 2b.

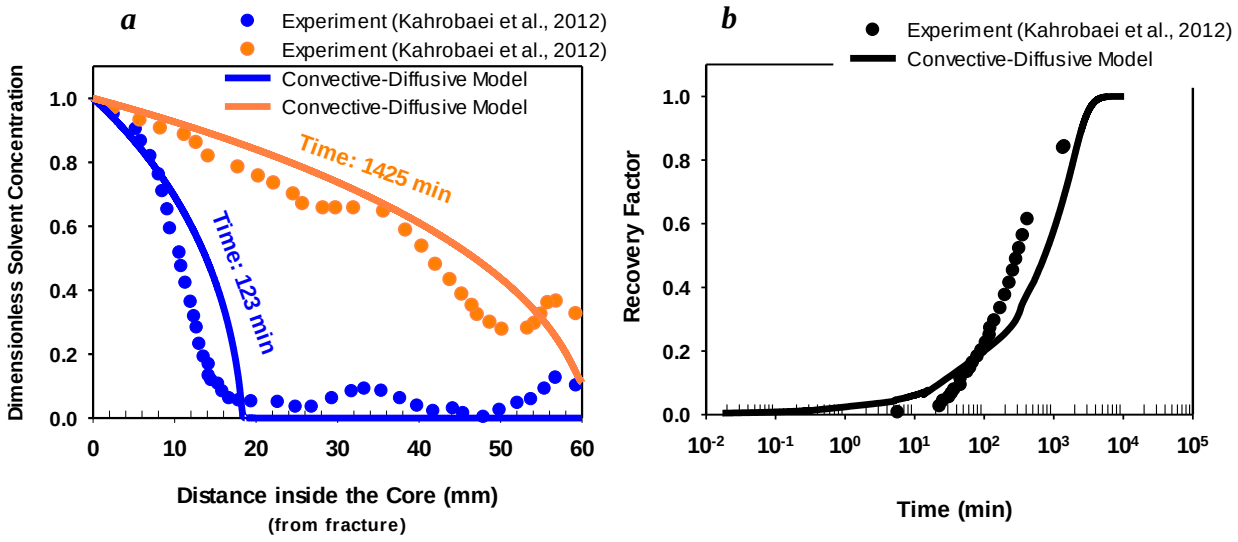


Figure 2. a) Solvent concentration profile at two different times inside the core, b) recovery factor of the solvent enhanced gravity drainage

5. Parametric studies

In the previous section, we demonstrate the capability of the proposed model to represent solvent penetration depth and oil recovery for the core scale experiments. In this section, we examine the effect of different parameters for a solvent-enhanced gravity drainage recovery from a matrix block in fractured rocks including Peclet number, viscosity, and density contrasts and the concentration dependency of diffusion coefficient by varying the n exponent. In fact, all of these parameters are controlled by solvent choice. Hence, it is important to choose the right solvent based on the petrophysical properties that are used in Peclet number, dimensionless density and viscosity definitions, and n exponent for any field before making decision of enhanced oil recovery methods.

Peclet number: Figure 3 shows the solvent concentration profiles at different times for Peclet number and viscosity ratios of 1 and 100, respectively. It can be seen that the concentration increases from the interface of fracture and matrix as it diffuses into the matrix block, mixes with oil, and reduces the oil viscosity. Diluted oil drains towards the fracture due to the gravity. In the other words, the process starts with diffusion dominant mass transfer and then it transitions to convective mixing and gravity drainage. It should be noted that at the front of solvent and oil interface, there is a sharp change in solvent concentration profile. This behaviour is due to exponential concentration dependency of the diffusion coefficient, similar trends were reported for VAPEX process with concentration dependent diffusion coefficient (Okazawa, 2009). Since solvent concentration ahead of interface is zero, it is assumed that there is no convective term, and just behind the interface where solvent concentration is non-zero, convection contributes to

the flow of oil toward fractures, therefore, there would be a rapid change in solvent concentration.

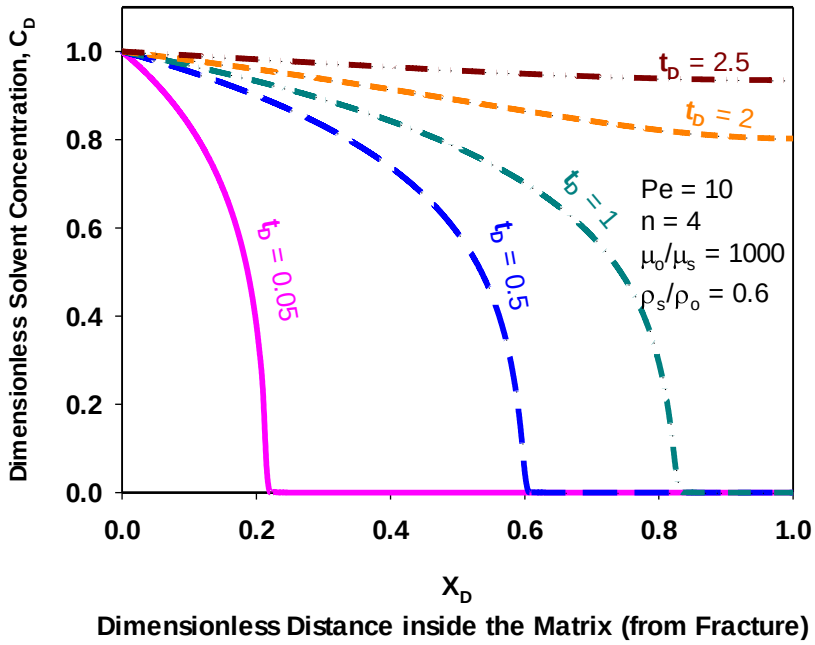


Figure 3: Concentration profile along the matrix block at different dimensionless time.

Figure 4 demonstrates the effect of Peclet number on the recovery of oil from matrix block. Figure 4a shows that as Peclet number increases, the depth of solvent penetration increases. Recovery factors are also shown in Figure 4b for different Peclet numbers. For Peclet numbers less than ten, diffusion is dominant compared to convection. Hence, the impact of convection on oil recovery factor becomes insignificant. In Figure 4c, we compare solvent concentration profile inside the matrix block for two Peclet numbers at early and late times. The results show that the difference between the penetration depths increases as the solvent assisted recovery process continues, which reveals that convective flow becomes dominant at extended time.

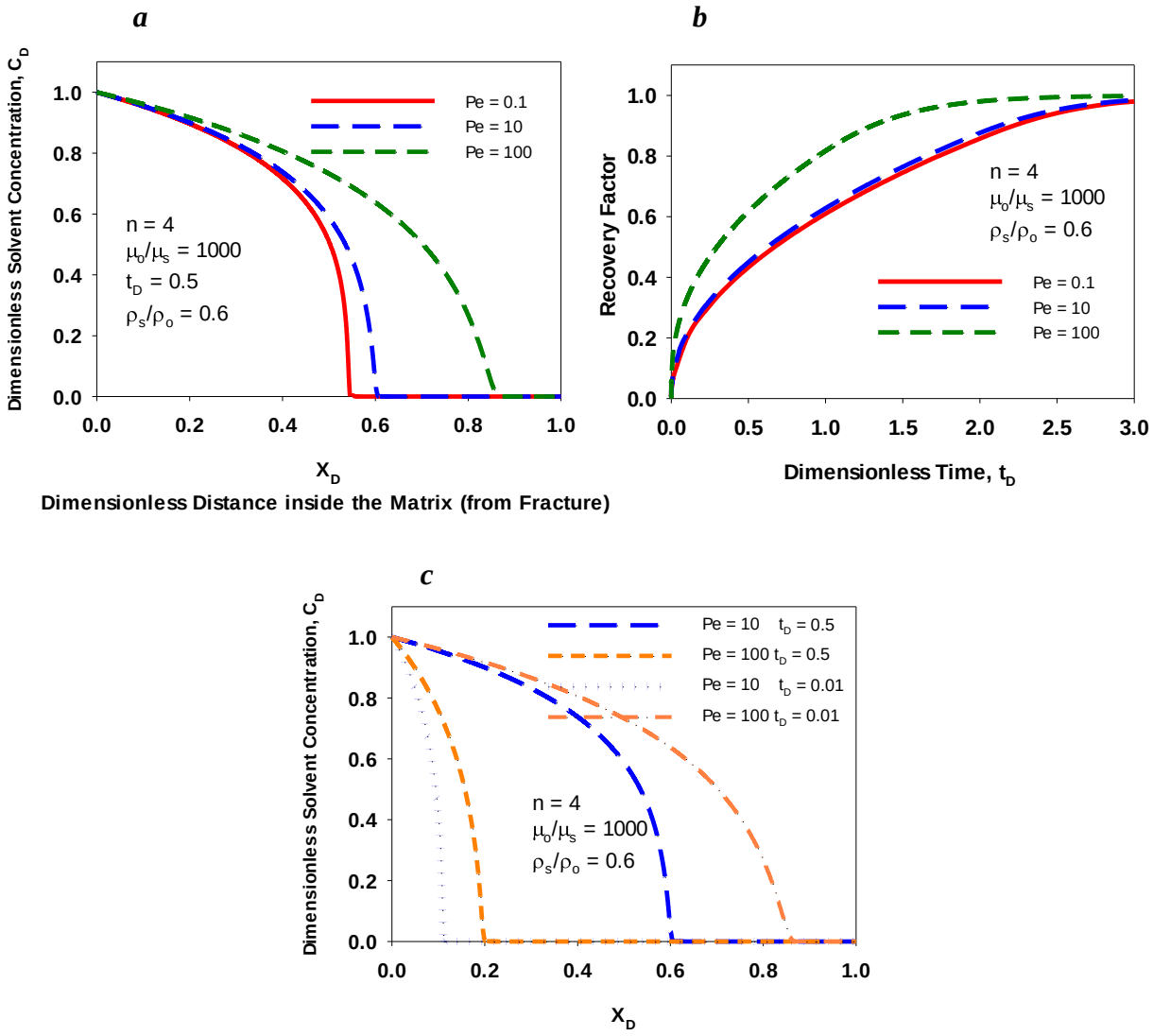


Figure 4: Comparison of the Peclet numbers, a) solvent concentration profile in the matrix block at dimensionless time of 0.5, b) oil recovery factor, c) solvent concentration in the matrix block for two Peclet numbers at two dimensionless times.

Solvent viscosity: Solvent viscosity is another parameter which controls fluid mixing or relative movement of each component in porous media. Figure 5 compares the concentration profiles and oil recoveries resulted from three different oil-solvent viscosity ratios. Lower solvent viscosity

translates to a higher mobility of oil-solvent mixture and in turns, to more rapid oil drainage from rock matrix block. Therefore, higher oil to solvent viscosity ratio which is due to different types of solvent (with one type of oil) in the recovery process shows better recovery performance as oil viscosity can be decreased to a lower order while all other parameters are kept constant.

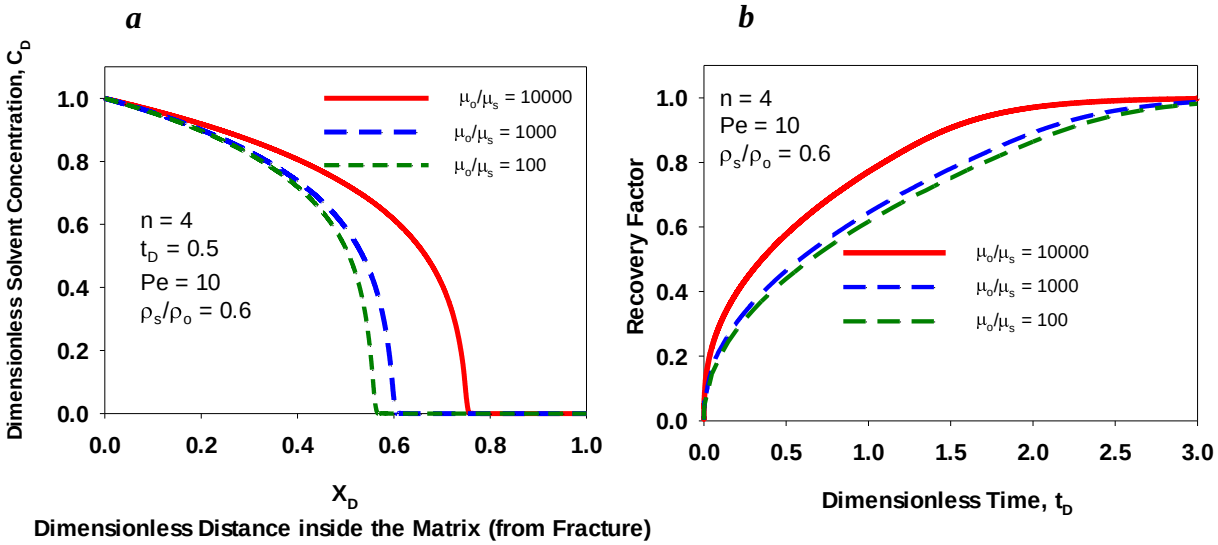


Figure 5: Comparison of the viscosity ratios (two oil with one order of magnitude difference in their viscosity), a) solvent concentration profile in the matrix block at dimensionless time of 0.5, b) oil recovery factor.

Concentration dependent diffusion (*n*-Constant): Petrophysical properties and viscosity of fluids, which are discussed through the effects of Peclet number and viscosity ratio are directly related to the convective mixing and gravity drainage process. Diffusive mass transfer is another key parameter which determines the rate of mass diffusion of solvent into the oil phase. So, its dependency on concentration is a key factor in controlling the depth of solvent penetration. Therefore, we study the effect of exponent to concentration, i.e. *n*-Constant. Figure 6 shows that

typical values of exponent can influence the rate of mass diffusion and recovery process from rock matrix block. Solvents which mix easily with oil have a lower exponent values and therefore result in higher recovery factors at a shorter time period.

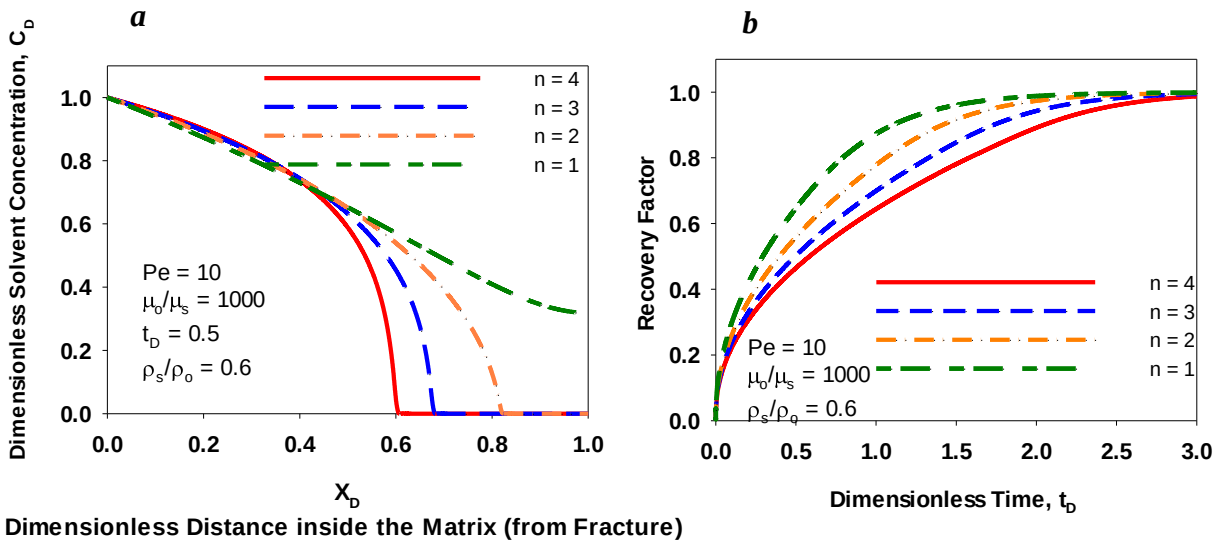


Figure 6: Effect of different exponent to concentration for diffusion coefficient, a) solvent concentration profile in the matrix block at dimensionless time of 0.5, b) oil recovery factor.

Solvent density to oil density ratio

Another parameter that can affect the rate of oil recovery in a gravity drainage process is density difference between solvent and oil. In this study this difference is developed in the dimensionless form of density ratio of solvent to oil. Most solvents are less dense than oil, therefore, this ratio is typically less than unity. However, for small Peclet numbers, i.e., <10, the effect of density ratio is negligible since convection is not dominant. Figure 7 shows the effect of density ratio for two different solvents with density ratios of 0.6, and 0.8 at the Peclet number of ten. It can be seen that as the ratio increases, oil recovery become slower which means gravity force becomes less

effective. Use of light solvents which raises the density contrast is favourable, however, it should be noted that light solvents have smaller diffusion coefficients that makes the mass transfer process slow. Thus, an optimum solvent to provide enough gravity force with an effective diffusive mass transfer process needs to be determined.

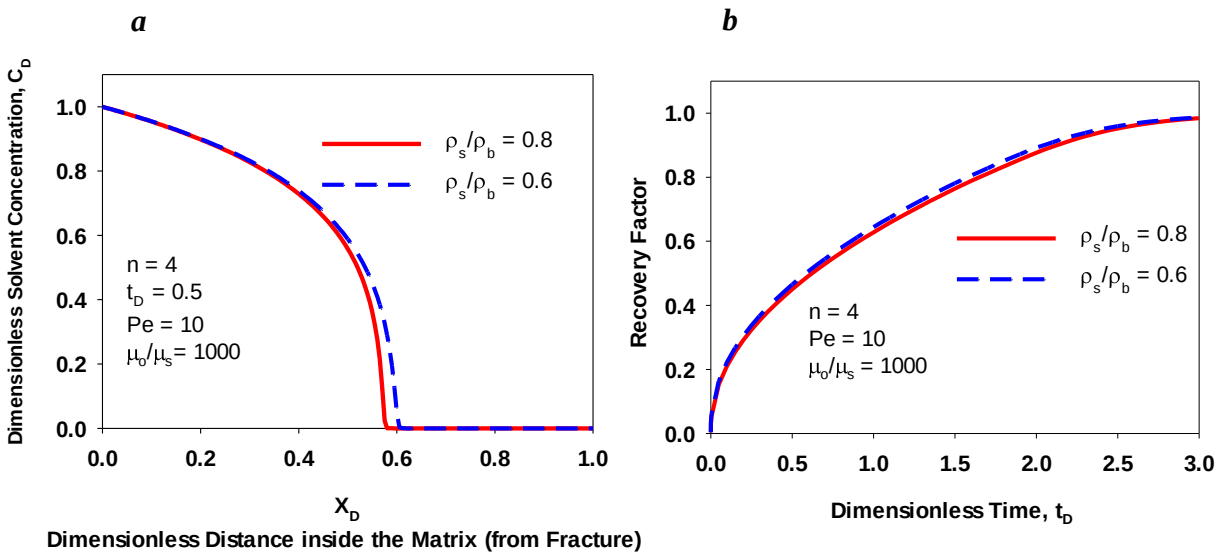


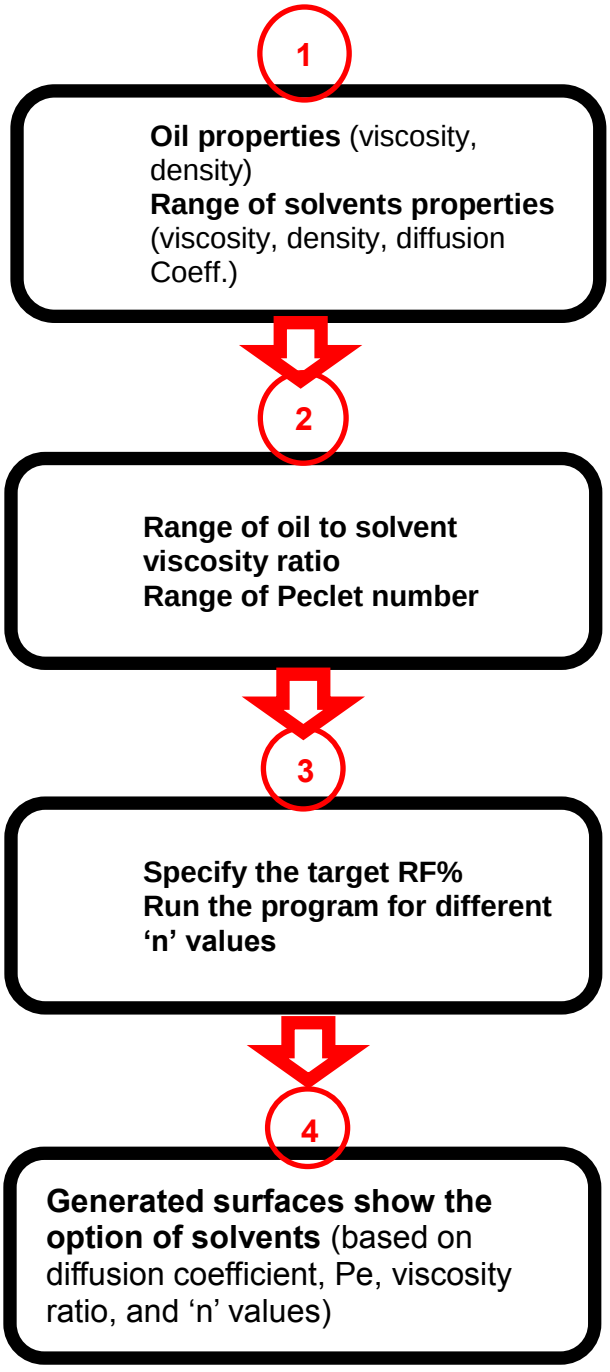
Figure 7: Effect of oil to solvent density ratio, a) solvent concentration profile in the matrix block at dimensionless time of 0.5, b) oil recovery factor.

6. Solvent optimization

To design a successful solvent assisted gravity drainage recovery process for fractured reservoirs, all parameters discussed in previous section should be thoroughly investigated. This means that based on the properties of oil, rock, and solvent, a desired recovery process can be optimized. We used these parameters to determine solvent type required to recover oil from a matrix block. Different exponents for concentration dependence of diffusion coefficient are considered separately for different optimizations. The algorithm shown in Figure 8 depicts how

optimized solutions are determined. Once it is run for each exponent values, it provides an optimum value for the desired recovery factor. We show the results for the recovery factor of 90%, as a target, for other recovery factors same procedure can be performed. An example of optimization graphs is shown in Figure 9. These graphs are associated with exponents of 1 to 4. It can be seen that as the exponent decreases from 4 to 1, the time required to produce oil decreases. Also each of the plots show that higher Peclet numbers deplete the matrix block faster especially in higher oil-to-solvent viscosity ratios.

Based on the laboratory analysis, once the exponent is determined for the solvent and oil, then appropriate graph shows the time required to recover oil from a matrix block (Peclet number and viscosity ratio can also be evaluated from laboratory data). This helps to estimate the operational cost, time, and the solvent required to run a solvent assisted gravity drainage oil recovery from a fractured reservoir.



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354 **Figure 8:** Optimization algorithm for specific oil properties.

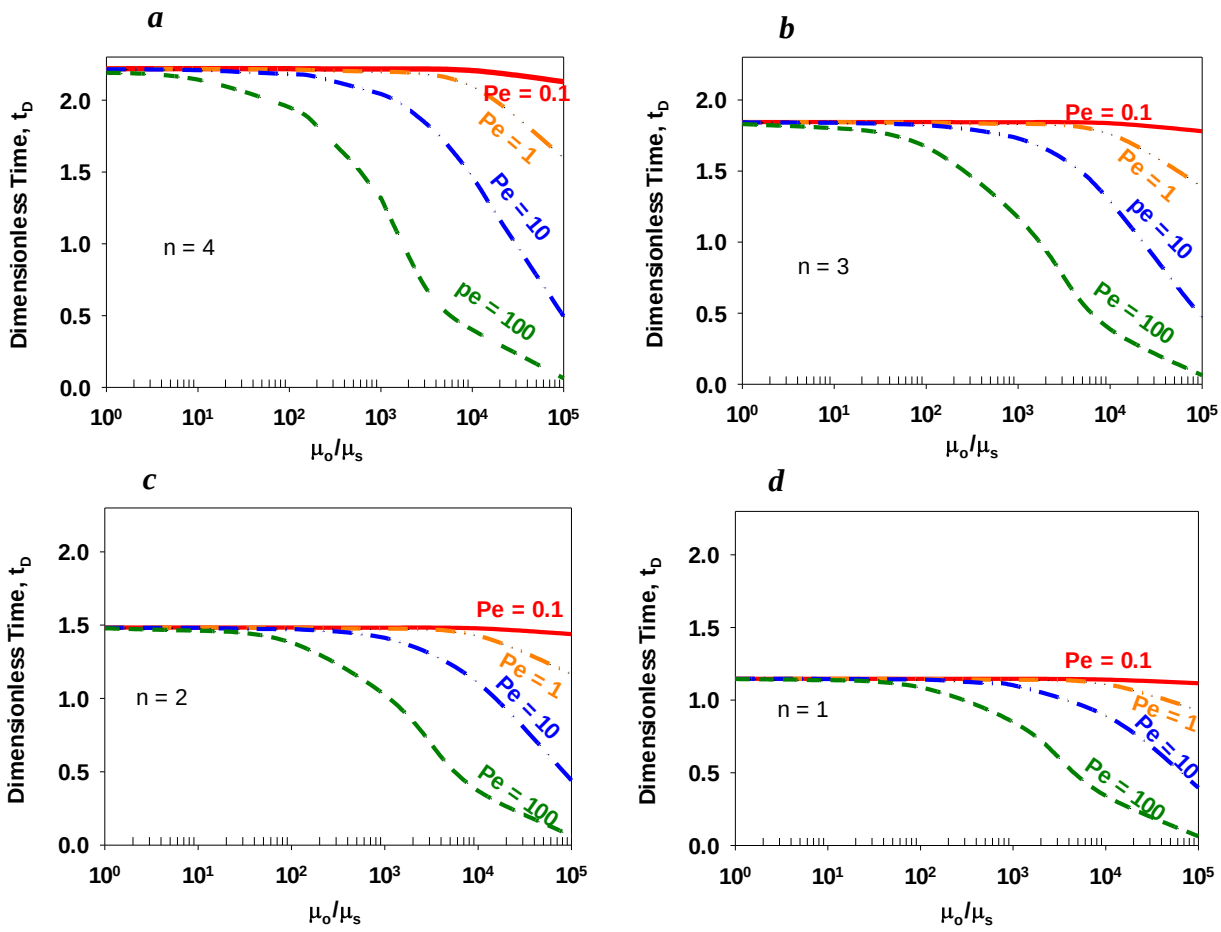

Figure 9: Optimized graphs for recovery factor of 90% with oil to solvent density of 0.6.

7. Conclusions

A model for fluid exchange between rock matrix block and its surrounding fracture is developed for solvent-aided gravity drainage. Low to high viscosity oil in fractured reservoirs where the permeability of matrix block might range from low to high values, can be analysed with the use of this model for solvent enhanced gravity drainage processes. Mass transfer, concentration dependent diffusion coefficient, and convective mixing were used to demonstrate the solvent

enhanced gravity drainage process in a single matrix block. The new model can accurately simulate solvent concentration profiles and oil recoveries from matrix blocks reported in solvent recovery experiments. Optimization of the recovery factor yields estimates of the time required to produce oil with a specific solvent. The method provides an easy and fast algorithm to choose the best solvents for gravity drainage recovery processes. This model can be implemented into the multi-phase flow simulators for accurate designs of solvent enhanced oil recovery processes from fractured reservoirs.

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